Responses to the Hawaii Renewable Energy Alliance's Information Requests

HREA-HECO-IR-1

On page 3, first paragraph, please provide examples of the contingency options in IRP referenced in the statement below.

> Just as IRP has to allow for the implementation of *contingency options* when planning assumptions and forecasts change, any competitive bidding process would have to allow for similar exceptions.

HECO Response:

In HECO's second IRP report filed on January 30, 1998 in Docket No. 95-0347, HECO explained the flexibility required in long-range planning and possible alternative future scenarios in sections 11.8 and 11.9 (p. 11-35 to 11-44). In HELCO's second IRP report filed on September 1, 1998 in Docket No. 97-0349, HELCO explained the flexibility required in long-range planning and alternative future scenarios in sections 8.7.4 and 8.7.5 (p. 8-31 through 8-37). MECO's second IRP filed on May 31, 2000 in Docket No. 99-0004 explained the risk and uncertainties faced by MECO in section 9.7.4 (p. 9-38 to 9-40).

HREA-HECO-IR-2

On page 3, third paragraph, please clarify the statement below. Is not the timing of as-available renewable energy generation just as important as firm capacity, e.g., to meet RPS? Also, is HECO implying that as-available renewable energy generation will not contribute positively to system reliability? If so, why not?

> Also, as-available renewable energy generation has different characteristics than firm capacity, and the *timing of when such resources are added to the utility's system* is *not nearly as important to the reliability of the system.*

HECO Response:

As-available energy generation and firm capacity have different characteristics. For example, as-available energy generation, such as that from wind turbines, run-of-the-river hydro and photovoltaics, are subject to the vagaries of nature, i.e., energy from wind turbines is available only when the wind blows, energy from run-of-river hydro units is available only when water is flowing, and energy from photovoltaic ("PV") units is available only when the sun shines on the PV panels. These resources are not dispatchable, i.e., the utility cannot call for specific amounts of power at scheduled times.

Firm capacity units, such as steam turbines (whether fired by fossil fuels or biomass), geothermal units, diesel engines or combustion turbines (whether fired by fossil fuels or biofuels), are dispatchable and can therefore provide required amounts of power at scheduled times to consumer power needs when they need it. Therefore, firm capacity units have a greater ability than as-available units of equal size to provide reliable power, i.e., customers can be provided with the amount of power needed when they need it (and at the desired power quality).

This is not to say that as-available resources do not contribute to system reliability. As-available resources can contribute to system reliability, especially when there is a firm capacity shortfall. However, in a relative sense, firm capacity units provide a much greater contribution to system reliability than as-available units of equal size. HECO's statement regarding the timing of the installation of resources was made with respect to meeting system reliability. In regard to meeting RPS, the timing of the installation of firm capacity renewable units would be more important than that of as-available renewable resources. As-available resources may generate less than expected values in any given year. As a hypothetical example, if a given entity was relying on run-of-the-river hydro to fulfill the bulk of its RPS requirements, than this entity could face an RPS deficiency during years of low rainfall. From this perspective, it is possible that firm, renewable generation could be more valued than as-available renewable generation.

HREA-HECO-IR-3

On page 3, fourth paragraph and continuing to page 4, please clarify if the statement below is a direct quote from the Commission Decision and Order (D&O) or a HECO paraphrase. HREA believes the D&O was limited a time period in question, e.g., 1996 to 2003. Also, would it not be more correct to say that we already have some forms of *retail competition* in Hawaii, e.g., net energy metering, third-party-owned, customer-sited DG and the retail wheeling that has been proposed by the County of Maui on the DG docket and alluded to by the County of Kauai in its comments?

> This docket was initiated at the close of the competition docket, in which the Commission determined that *retail competition would not be appropriate for Hawaii*, given certain factors that are unique to Hawaii and which distinguish Hawaii from the mainland.

HECO Response:

HECO confirms that the paragraph cited from page 3 of HECO's SOP is not a direct quote from a Decision and Order of Docket No. 96-0493. A direct quote from Decision and Order No. 20584 ("D&O 20584") in Docket No. 96-0493, page 14, is provided below:

> "Electric industry restructuring should only be initiated if it is in the public interest. Developments in other states indicate that, at best, implementation of retail access would be premature. In addition, projections of any potential benefits of restructuring Hawaii's electric industry are too speculative and it has not been sufficiently demonstrated that all consumers in Hawaii would continue to receive adequate, safe, reliable, and efficient energy services at fair and reasonable prices under a restructured market, at this time. Accordingly, the commission does not find it is in the public interest to completely restructure the electric industry, at this time. We will continue, however, to keep a watchful eye on restructuring experiences in other states. In the alternative, the commission finds that it is in the public interest to work within the current regulatory scheme to strive to improve efficiency within the electric industry[9]."

HECO does not agree that D&O 20584 was applicable to a limited a time period such as 1996-2003. The date of the Decision and Order is October 21, 2003, and contents of the order

[9] Hawaii is different from other states because, without interconnection to other states' energy transmission grid, Hawaii does not need to respond to the actions of its neighbors, and Hawaii does not have the advantages and disadvantages associated with being connected with other states.

do not indicate that Hawaii will become ripe for retail access in the near future. As stated on page 9 of the D&O:

> "Since 1996, approximately 24 states and the District of Columbia have either enacted enabling legislation or issued regulatory orders implementing retail access. The primary rationales for these initiatives have been that competition will tend to reduce prices relative to those that have existed under regulation and that competition will give consumers greater choice. Recently, several states discovered that competition is not materializing exactly as predicted, and many states are now reassessing the environment and the future of electric restructuring. While some have chosen to reinforce efforts to develop a competitive retail electric market, others have opted to return to previous regulatory frameworks."

HECO does not agree that it would be more correct to say that there are "already some forms of retail competition in Hawaii in terms of net energy metering, third-party-owned, customer-sited DG and the retail wheeling that has been proposed by the County of Maui on the DG docket and alluded to by the County of Kauai in its comments." In a basic retail competition model, there are four primary entities that make up the market structure: (1) the consumers of electricity; (2) aggregators, who pull together the load and service requirements of a variety of consumers and then deal with Retail Electric Providers for the supplies of generation and other services; (3) Retail Electric Providers, which are essentially the business organizations that arrange and administer the transactions between the suppliers (generators) and consumers (aggregators or individual consumers) of electrical energy and services; and (4) the Generators, which may be investor owned utilities, marketers or independent power producers, all of whom can generate electricity and provide associated services or can secure supplies of electrical power and services. In this model, individual consumers or aggregators purchase electrical energy and services from the Retail Electric Provider of their choice. The

Retail Electric Provider, in turn, purchases electrical energy and services from the Generator of their choice.

In the case of net energy metering, there is no business transaction between the Generator and the consumer since they are one and the same. The consumer basically avoids purchasing a portion of his or her electrical energy from the utility. This is different from the retail competition model.

Third-party-owned, customer-sited DG is basically self-generation which is not similar to the retail competition model described above.

With respect to retail wheeling, HECO is not clear what HREA is referring to when it states "we already have some forms of retail competition in Hawaii, e.g., …retail wheeling that has been proposed by the County of Maui on the DG docket and alluded to by the County of Kauai in its comments." HECO is not aware of where retail wheeling exists in Hawaii. Furthermore, without the specific citation of the County of Kauai's comments in which it purportedly alludes to retail wheeling as being a form of retail competition, HECO cannot provide comments.

HREA-HECO-IR-4

On page 6, the first sentence of the first paragraph, and the first sentence of the second paragraph read as follows:

> An *alternative* competitive procurement process was implemented in Hawaii as a result of PURPA (page 6); and
>
> Utilities in Hawaii also have used a Request for Proposals ("RFP") process to solicit proposals for new generation from IPPs.

Given the above, HREA has the following questions:

1. While the implementation of PURPA did result in competition here and on the mainland, would HECO agree until recently the HECO family did not plan for PURPA contracts for as-available power?
2. How would HECO propose to incorporate future, unsolicited PURPA contracts, into IRP?
3. Please provide the specific cases where the second approach was employed, and what were the results?

<u>HECO Response:</u>

1. HECO is unclear as to how HREA is using the term "until recently" and "did not plan for" in this IR. By its very nature, as-available power from a non-utility generator (i.e. PURPA contract) is available when it is available. Therefore, utilities must have plans that take into account the fact that as-available power may not be available. Notwithstanding this, page 3 of HECO's statement of position in this docket explains the process by which qualifying facilities are allowed to submit offers to sell power to the utility. In addition, HECO develop plans for its system that takes into account the as-available generation currently provided by Chevron and Tesoro. Also, in MECO's second IRP file in May 2000, MECO included plans for as-available power from a wind farms in its preferred plan.

2. Page 3 of HECO's statement of position referred to by HREA explains the current process for handling PURPA contracts and HECO's use of RFPs in the past. HECO's position on establishing a process for competitive bidding process is described in response to issue 2 (Exhibit A, p. 15). HECO has a number of concerns regarding the potential shortcomings of competitive bidding process that should be addressed in the design, development and implementation of a competitive bidding program. Without resolution of these issues, HECO could not support the institution of competitive bidding for acquiring or building new resources in Hawaii.
3. It is not clear what is meant by HREA as the "second approach". If it is referring to specific cases where the utilities have used a Request for Proposal process to solicit proposals for new generation from IPP's, then HECO's Kahe Unit 7 Purchased Power Alternatives RFP, dated June 4, 1987, was consistent with this approach. As a result of the RFP, HECO signed PPAs with Kalaeloa Partners, L.P. and AES-Barbers Point, Inc. (now known as AES Hawaii, Inc.).

HREA-HECO-IR-5

On page 7, the first paragraph, would HECO agree that the buyers needs, in the following statement, could include acquiring new generation to meet our RPS?

> The key points are that the process is only implemented if it benefits the buyer using the process, and the products acquired using the process will meet the buyer's needs.

HECO Response:

As stated on page 7 of HECO's SOP:

> "Generally, a product buyer will implement a competitive bidding process in order to acquire a product that meets the buyer's needs (i.e., in terms of quality, quantity, and time and assurance of delivery) at the lowest cost."

As HECO understands it, HREA's question might be restated as "Would a buyer have a need to acquire new generation to meet the RPS?" It is conceivable that, yes, a buyer could have a need to acquire new generation to meet the RPS, provided that the new generation has characteristics that would allow it to be counted toward meeting the RPS. However, other options would also need to be considered. For example, DSM resources could help meet the RPS. Also, converting existing fossil-fueled generation to use a mixture of fossil fuel and a biofuel could also help meet the RPS. In other words, the buyer may not necessarily need to acquire new generation to meet the RPS.

HREA-HECO-IR-6

On page 7, the third paragraph, does the following statement represent a shift in HECO's priorities? Please explain how HECO will acquire renewable resources.

> Under state energy policy, the *utility's focus is first on acquiring new renewable energy generation.*

HECO Response:

The referenced statement does not represent a shift in HECO's priorities. HECO has long supported the increase in renewable energy on our utility systems. To this end, as HREA is aware, three wind farms (two on the Big Island and one on Maui) will add about 60 MW of wind generation in the State in the near future.

The discussion in HECO SOP on page 7 covers competitive bidding objectives, not how the utility will acquire renewable resources. HECO states that to establish these objectives, the purpose of competitive bidding must be identified. In general, the purpose is to meet the buyer's needs (quality, quantity, time and lowest cost). A number of factors must be considered to meet this purpose: reliability, characteristics of the generating unit, control of the unit, state energy policy, firm versus as-available, costs, transmissions needs, time, new accounting practices and other factors. The purpose of this docket is to discuss how the utility could acquire new generating units (conventional or renewable).

HECO's strategy for acquiring renewables can be grouped into three main thrusts: (1) pursue commercially available renewable energy generation in the near term; (2) pursue activities that can increase the number of intermittent renewable energy technologies (i.e., wind) on the electric grid, and in parallel, and (3) accelerate RD&D for emerging technologies and resources that are not currently commercially available or economically viable in the near term.

This renewable strategy aims to pursue commercially available renewable energy generation in the near term, and in parallel, seek ways to increase intermittent renewable systems (i.e., wind) and invest in research, development, and demonstration projects (RD&D) for emerging technologies and resources that are not currently commercially available or economically viable in the near term.

HREA-HECO-IR-7

On page 7, the fourth paragraph, how is the potential use of energy off-set technologies and storage being evaluated as alternatives to firm capacity?

> Hawaii utilities must have adequate assurances that *new, firm capacity* generation will be added when it is needed. Hawaii utilities do not have the option to acquire power from other jurisdictions, or even other islands, to backup the unfulfilled commitments of IPP developers of generation.

HECO Response:

HECO considers storage technologies as a part of the IRP process. For example, HECO analyzed a combination PV and battery storage supply side resource as a part of its third IRP, and HELCO analyzed pump storage hydro in its second IRP. Pump storage hydro was also considered in HECO's third IRP, but was screened out due to permitting, environmental, and land use issues.

HECO is not familiar with the term used by HREA, "energy offset technologies". If this is a generic description for technologies that will reduce the need for new generation, then HECO does evaluate DSM and CHP programs as a part of its IRP process.

HREA-HECO-IR-8

On page 8, HECO first introduces the issue of the company's debt/equity ratio and potential impacts if additional purchase power is acquired.

See also HREA-HECO-IRs-9, 26, and 27. Please clarify:

1. Do HECO's concerns apply primarily to interest rates on bonds for new generation, or also to other types of debt financing?
2. Is there a recognized or verifiable relationship between the amounts (percentages) of purchase power to a specific credit "downgrading" that HECO suggests would occur if there were additional purchase power were incurred? Please provide quantitative examples.
3. Please provide the amounts/percentages of the various types of financing employed by HECO (Oahu only) over the past 10 years?
4. Therefore, does the potential "downgrading" affect HECO's financing of generation assets the same as T&D assets? Please explain.
5. What would be the anticipated impacts if HECO did not make the next generation investments on Oahu? Specifically, what would be the increased interest costs as a percentage of monies invested?
6. Given an IPP provides the next increment on Oahu (item 5), would there be an impact on the next round of T&D investments by HECO? Specifically, what would be the increased interest costs as a percentage of monies invested?

HECO Response:

1. As discussed in greater detail in HECO's SOP, Exhibit A, page 24, in this proceeding, and extensively in HECO T-21 in Docket No. 04-0113, long-term, fixed payments in purchase power contracts impact a company's debt/equity ratio. Currently, HECO's purchase power contracts impact the debt/equity ratio as a result of debt being imputed by credit rating agencies; however, as a result of changes in accounting standards, HECO's accounting treatment may change. The changes in accounting standards may result in more actual debt being shown on HECO's financial statements as a result of either: 1) capital lease treatment or 2) consolidation of an IPP which is more highly

leveraged than HECO. A company's debt/equity ratio is one of many considerations in evaluating its overall credit quality. Credit quality impacts the cost of all the Company's sources of future financing including any new debt issuances. Debt/equity ratio is also a measure of risk to shareholders. Higher debt is more risky; therefore, a higher debt/equity ratio will increase return expectations for equity. See also response to (4).

2. Credit rating agencies do not quantify relationships that directly translate to credit ratings; however, general guidelines are provided and are considered along with other non-qualitative factors. The Standards & Poors' ("S&P") article "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised" discusses indicative credit ratings for three key financial ratios: 1) funds from operations/interest coverage, 2) funds from operations/total debt, and 3) total debt/total equity. (See the response to CA-HECO-IR-19 for a copy of the S&P report.) As discussed in response to CA-HECO-IR-19, S&P imputes debt and interest expense for the Companies' existing firm capacity long-term contracts. Imputed interest lowers the funds from operations/interest coverage ratio, which lowers the indicative credit rating for this ratio. Imputed debt lowers the funds from operations/total debt ratio, which lowers the indicative credit rating of this ratio. Imputed debt increases the total debt/total capital ratio which lowers the indicative credit rating of this ratio. Overall, this has a negative impact on the credit rating indication from this quantitative portion of their overall credit evaluation.

In response to the impacts of imputed debt, HECO has decreased its other (actual) debts and increased its equity to maintain the debt/equity ratio.

3. HECO (Oahu only) capitalization is shown on attached page 4. Short-term borrowings have been comprised of commercial paper issuances and intercompany borrowings from subsidiaries. Long-term debt has been comprised of special purpose revenue bonds, first mortgage bonds and unsecured notes. Hybrids are comprised of quarterly income preferred securities.
4. HECO does not plan specific financing for individual projects or types of assets (such as generation or transmission and distribution assets). Financing is planned for the Company's total needs, targeting certain proportions of debt and equity in the capital structure. A credit rating downgrade would have a negative effect on the cost of future financing for HECO.
5. HECO cannot speculate as to the impact of not building the next generating units. The impact is dependent upon what happens in the alternative. There will be significant impact on the Company's operations and ability to serve load, as discussed in Exhibit A. The impact of HECO not building the next generating unit extends far beyond the financial impacts. The credit impact of a purchase power contract is dependent on the specific terms of the contract. In general, more risks (e.g., long terms, fixed payments) being assumed by the purchaser will result in more negative impact on its credit and higher financing costs as a result.
6. As discussed in (5), HECO cannot speculate as to the impact of purchasing power since it is dependent on the specific terms of the contract; however, if a purchase power contract causes HECO to be more leveraged (i.e., have more debt on its balance sheet or having credit rating agencies impute debt), HECO would propose to rebalance its capital structure (i.e., reduce other debt and increase equity). Such rebalancing will

result in a capital structure that has the same debt and equity ratios as before the purchase power contract which should account for the financial implications of the purchase power contract. As a result, other financings should not be negatively impacted. There will, however, be a cost to ratepayers resulting from more equity financing and less debt financing. Since equity is relatively higher cost than debt financing, this will result in higher costs to ratepayers. Alternatively, if HECO does not rebalance its capital structure, the increased riskiness of its financial structure will result in higher costs of both debt and equity financing since investors will expect higher returns due to the increased risks they are taking.

HREA-HECO-IR-9

On page 8, the last paragraph, and pages 4 and 14 (Exhibit A) please clarify HECO's statements below. Specifically:

1. Is HECO implying that there should be no purchase power or only no additional purchased power? Please explain.
2. More importantly, is HECO suggesting that existing purchase power in the islands has caused operational or reliability problems? Provide examples as appropriate.
3. How long has HECO monitored the source and duration of power outages?
4. For a reasonable period of time (say the past 10 years or so on Oahu), what is the percentage of outages and total outage hours caused by generation versus T&D?

Regulatory commissions have recognized that utilities have an obligation to serve and provide reliable service, and have an obligation to do so at lowest reasonable cost. Regulatory commissions also have recognized that acquisition of energy and capacity to meet the needs of customers remains the responsibility of the utility, and that these functions *should not be delegated* to an independent entity. (Page 8, PSOP).

The isolated nature of the island's electrical system places a premium on reliability of power supply and increases the risk of project default and/or the failure of the independent generator to deliver the power. Unlike the mainland, Hawaii's electric utilities cannot resort to purchases of energy from the market during periods of generation shortfall if the project does not deliver the power as required under the contract. (Page 4, Exhibit A).

Contractual arrangements for the purchase of power may sometimes constrain the flexibility to manage system issues that evolve over time. Modifications to generating units needed to meet new operating requirements, such as cycling on and off or being operated at lower load levels, may be difficult to obtain. Project financing agreements may limit the ability of the IPP to agree to modifications, even if the utility compensates the IPP for making the modifications (Page 14, Exhibit A).

<u>HECO Response:</u>

1. To clarify, HECO wrote the following statement, which begins on the bottom of page 8:

> "Thus, the host utility should play a major role in the competitive bidding process, including: (1) designing the RFP documents, evaluation criteria, and power purchase agreement; (2) managing the RFP process,

including communications with bidders; (3) evaluating the bids received; (4) selecting the bids based on the established criteria; (5) negotiating contracts with selected bidders; and (6) competing in the solicitation process with a self-build option, if feasible."

This paragraph emphasizes the importance of the host utilities' role, however, it does not imply that purchase power should be excluded from the competitive bidding process. Page 14 of Exhibit A makes 3 key points: 1) Competitive Bidding and procurement of power resources through IPP power purchase agreements may reduce the utility's ability to manage the unique grid requirements of isolated utility systems, 2) Competitive bidding and procurement through independent power purchase agreements may reduce utility and regulatory control over utility system operations, and 3) Various forms of competition already exist that can achieve the goals of competitive bidding. The point of this discussion was to recognize the potential disadvantages of competitive bidding. This section of Exhibit A was immediately preceded by a section which described the potential benefits of competitive bidding. Therefore, HECO is not implying that purchase power should be excluded from the competitive bidding process. Please refer to the response for CA-IR-4, which also relates to the issue of IPP integration on an isolated island system.

2. The existing Independent Power Producers have caused operational or reliability problems, as explained in the following paragraphs.

On the HECO system, Independent Power Producer ("IPP") forced outages have been mostly mitigated by operating with adequate spinning reserve. There were three load shedding incidents involving AES since commercial operation of AES in 1992. The first occurred on November 5, 1996, when inclement weather caused the Waiau-Koolau #1 line to trip. The loss of the Waiau-Koolau #1 line tripped Waiau #7 and frequency drooped to 59.20 hz. Shortly after, Kahe 5 tripped due to high boiler furnace pressure and system frequency further sagged to 58.58 hz. Approximately seven minutes after the Kahe 5 trip, AES tripped due to loss of control air and frequency sagged to 57.2 hz, resulting in load shedding.

The second AES incident occurred on May 10, 2002, when AES tripped from 180 MWs due to a technician error. System frequency drooped to 58.42 hz and load was shed via the kicker block.

The third AES incident occurred on December 19, 2002, when AES tripped due to a catastrophic failure of a boiler feedpump flange, which damaged critical electrical components. H-Power and Kahe Unit 3 also eventually tripped while responding to the AES trip. System frequency eventually sagged to a low of 57.7 hz, resulting in load shedding.

Puna Geothermal Venture's ("PGV's") normal rating is 30,000 kW. During 2001, PGV experienced changes in the characteristics of its steam source, and generally exported to HELCO between 22 MW and 28 MW at top load. In April 2002, PGV's normal top load rating was reduced to an average of 5.6 MW due to blockage of a source well and decreasing steam quality from another source well. The average rating for all of 2002 was 8.5 MW. In 2003, PGV's normal top load rating averaged 21 MW. In 2004, PGV generally exported between 25 and 26 MW.

By letter dated March 25, 1994, Hilo Coast Processing Company ("HCPC") notified HELCO of its intent to abandon the production of power on March 26, 1997, prior to the scheduled expiration of the then current power purchase contract with HELCO, due to the absence of adequate sugar legislation. On December 12, 1994, HCPC filed a voluntary petition under Chapter 11 of the United States Bankruptcy Code and on that date notified HELCO of its intent to shut down its power plant in December 1994, that is, to default on its contract. In order to keep the plant operating after December 25, 1994, HELCO obtained a temporary restraining order ("TRO") on December 23, 1994, which required HCPC to continue operating the plant through January 6, 1995, in exchange for an additional capacity payment plus payment of HCPC's additional energy costs. The TRO was later extended and modified pursuant to stipulations between the parties. On March 24, 1995, HELCO executed an amended and restated power purchase agreement with HCPC, and the agreement became effective in August 1995 after the Bankruptcy Court dismissal of the bankruptcy proceeding. In this situation with HCPC, which was in bankruptcy and had unilaterally terminated its agreement with HELCO two years before the early termination date, HELCO did not have the option of renegotiating based on its avoided costs. Instead, the purchased power rates basically were set to cover HCPC's costs. (HELCO's firm capacity payments increased from approximately $2.4 million under the previous agreement, to approximately $3.5 million [on an annualized basis] in 1995 and approximately $5.1 million per year through 1999. In addition, HELCO was required to make a $6 million loan to HCPC to pay for its employee benefits and severance pay obligations and to provide funds for any necessary capital improvements to HCPC's power plant, and to provide a $2 million revolving line of credit to HCPC for fuel purchases, for which HELCO incurred a substantial financial obligation.

In 1988, MECO experienced nine rolling blackouts on the island of Maui. By Order No. 9978, filed October 18, 1988, in Docket No. 6330, the Commission opened an investigation into, among other things, the cause or causes of the outages and MECO's plans and programs to prevent future rolling blackouts. As stated by MECO in Docket No. 6330, Hawaiian Commercial and Sugar Company's ("HC&S") failure to meet its firm commitment contributed to eight of the rolling blackouts Maui experienced in 1988. (In 1988, MECO and HC&S had a power purchase agreement dated July 31, 1980, which was approved in Decision and Order No. 6405, filed October 8, 1980, in Docket No. 4072.) (The operating restrictions placed by the Environmental Protection Agency on Maalaea Unit 12, which MECO had planned to place in service in April 1988, also contributed to the 1988 rolling blackouts.)

HELCO purchased capacity and energy from Puna Sugar Company, Limited ("Puna") starting in 1971 pursuant to a contract dated April 15, 1969 and subsequent amendments thereto. (Puna generated electricity for sale to HELCO primarily from bagasse.) On January 15, 1982, Puna gave notice of termination of the contract, effective January 15, 1985, due to Puna's intent to discontinue its sugar cultivation and manufacturing business. Subsequently, Puna agreed to withdraw its notice of termination, and entered into an Amended and Restated Power Purchase Contract dated October 4, 1984. (Puna continued to generate electricity primarily from wood chips.) Subsequently, HELCO and Puna entered into good faith negotiations with respect to HELCO's acquisition of the Puna Biomass Power Plant. Puna desired to terminate its power purchase contract with HELCO due to substantial reductions in HELCO fuel oil prices (and the resulting substantial decrease in HELCO's avoided energy cost), and to Puna's difficulties in obtaining an economic, reliable and adequate supply of wood chips, which resulted in Puna suffering substantial economic losses. HELCO's acquisition of the Puna Plant was approved by Decision and Order No. 9855, filed July 29, 1988, in Docket No. 6181. As a result of the acquisition, it cost HELCO somewhat more to generate electrical energy than it cost HELCO to purchase electrical energy pursuant to the terms of the power purchase contract with Puna. However, HELCO and its customers did derive benefits from the acquisition, as explained in the application in Docket No. 6181.

See also the response to HREA-HECO-IR-16.

3. Pursuant to General Order No. 7, which was promulgated by the Commission in 1965, the utilities are required to "keep records of all planned and unplanned interruptions of service of more than one minute duration and shall make an analysis of the records for the purpose of determining steps to be taken to prevent recurrence of such interruptions. Such records should include the cause, date, time and duration of the interruption as well as corrective action taken and other pertinent information."

4. HECO objects to this information request on the grounds that, pursuant to Prehearing Order No. 20923, filed April 23, 2004, in this proceeding, a party "shall not be required, in a response to an information request, to make computations, compute ratios, reclassify, trend, calculate, or otherwise rework data contained in its files or records." HECO files its Annual Service Reliability Report on an annual basis with the Commission. (HECO's last report, for the year 2003, was filed by letter dated September 21, 2004.) The durations and causes of the outages that occurred in 2003 are identified in the report. However, the percentage of outages and total outage hours are not broken down by the requested "generation" and "T&D" categories.

HREA-HECO-IR-10

Ref: HECO Companies SOP, Page 9.

Please provide specific evidence (e.g. case studies) supporting HECO's claim that utility projects are now competitive from a financial perspective.

HECO Response:

In a number of recent RFP processes, the utility's own self-build project has been selected as the winning bid. Specific examples include the following listed below:

1. Portland General Electric selected its self-build project, the 350 MW gas-fired combined cycle Port Westward project as one of the resources in the portfolio selected as a result of its 2003 Request for Proposals for power supply resources. The resource selection was approved by the Commission in Order Nó. 04-375.
2. PacifiCorp selected its own self-build option, the 525 MW Currant Creek Project in the peak bid category of its 2003 RFP (RFP 2003-A). In the baseload category, the Company selected the Lake Side Power Project, a 534 MW gas-fired combined cycle project. This project was proposed as a turnkey option by Summit Energy. Once completed, the facility will be owned and operated by PacifiCorp.
3. Progress Energy Florida issued a Request for Proposals in October 2003. The Company decided that building the 4th phase of its Hines Energy Complex facility was the most cost effective option of the bids received.
4. Florida Power & Light Company selected its own Turkey Point power plant expansion as the most cost effective option after comparing the project to more than 40 options.

HREA-HECO-IR-11

On page 10, last paragraph, would HECO consider HREA's proposal (Model 1, as discussed on pages 10 to 11 of our PSOP) for projects that that HECO would like to build? Is this not an option that HECO could choose to employ now?

HECO Response:

At this time, HECO is not in agreement with "Model 1" for a number of reasons that include the following:

The Model 1 approach would require the host utility to provide detailed cost information of a proposed facility (facility bidding baseline) based on the IRP, including capital and operating costs. HECO is concerned that providing the level of detail requested could send the wrong price signals to bidders and could limit the benefit of competitive bidding if bidders base their price on the cost of the facility bidding baseline rather than competing with their own unique project costs. If such a pricing proposal establishes an artificial floor, this will conflict with the overall objectives of competitive bidding, and can lead to costs to consumers that are higher than would be established in a competitive process.

As discussed in more detail below, use of a standard offer contract is not consistent with the type of bidding process for long-term resources envisioned, but is more typical of short-term resources for standardized products. This is contrary to HECO's approach to allow all supply-side resources to compete, with unique characteristics and contract requirements.

HECO has major reservations about the role of the Independent Contracting Agent (ICA), who under HREA's Model 1 approach, is responsible for reviewing and evaluating the bids and making a recommendation to the PUC for project award. In its Model 1 proposal, HREA makes no mention of who bears the risk if the project selection by the ICA results in significant project liability and costs to customers. HECO is not in agreement with Model 1 because it does not provide the utility with input into the bid evaluation and selection process, instead delegating functions and responsibilities to an "independent contracting agent" with no fiduciary responsibility. Such a role is not typical of other RFP processes, where the utility is actively involved in the RFP process, a role recognized by regulators and third-party bidders as a reasonable role for the utility.

Therefore, in HECO's view, the Model 1 process as outlined is more akin to a short-term solicitation for standard products (e.g., establish target price, use a standard offer contract, and establish the role of the ICA to merely compare IPP bids to the baseline). Presumably, non-price factors are not considered and only objective factors are evaluated by the ICA.

HREA's proposed Model 1 includes the use of a "standard offer contract" to be used for the "purchase of power from independent power producers". As discussed in other forums, even though many of the power purchase agreement ("PPA") provisions can be "standardized", there are still a significant amount of PPA provisions that may not be subject to standardization.

HREA-HECO-IR-12

On page 11, the second paragraph, HECO asserts that DSM and CHP are different from traditional supply-side resources. Would that be because they are actually demand-side resources?

HECO Response:

DSM by definition refers to demand-side resources. CHP differs from traditional supply-side resources such as central station generation mainly because it is a type of distributed generation ("DG") resource, which is smaller in scale and located at or nearby the location of energy use. It is inappropriate, however, to characterize CHP and other forms of DG as a demand side resource. Extensive testimony was presented to this effect by HECO in the DG Investigative Docket No. 03-0371. As stated on pages 42-43 of HECO RT-1 in that docket:

> "DSM Programs are designed to influence the use of energy. DG is a resource that supplies energy. The distinction between the use and supply of energy was made by the Commission in its Framework for Integrated Resource Planning ("IRP") (Decision and Order No. 11630, Docket No. 6617). The IRP Framework defines DSM Programs as:
>
> "... programs designed to influence utility customer *uses* (emphasis added) of energy to produce desired changes in demand. It includes conservation, load management and efficiency resource programs." (See IRP Framework, Section I, page 1.)
>
> HECO maintains that the inclusion of the word "uses" implies that the IRP Framework intended to apply the term "DSM" only to those measures that affect how customers use energy, not how it is generated.
>
> The IRP Framework definition of Supply-side programs is:
>
> "... programs designed to supply power. It includes renewable energy." (See IRP Framework, Section I, page 3.)
>
> Under this definition DG is clearly a supply-side resource, and not a DSM measure."

The key differences between DG and DSM are described in further detail in the HECO Companies' Opening Brief on pages 59 to 63 (including the references to the record and the authorities cited in the Opening Brief) and in HECO RT-1 pages 43-59, in Docket No. 03-0371.

In addition, with respect to the differences between DG and DSM, the HECO Companies' Opening Brief discussed (1) the differences between DSM measures and DG resources in terms of ownership, operation and maintenance (page 60), and (2) the major differences between the HECO Companies' proposed CHP Program and their DSM programs, such as the Residential Efficient Water Heating Program, which provides incentives to customers who install solar systems (pages 60-62).

Further, the HECO Companies' Opening Brief discussed that unlike the HECO Companies' proposed CHP Program, DSM programs are not currently designed so as to avoid any "burden" on non-participants. Incentives are paid to customers for "cost effective" programs, even where individual customer rates are increased when the utility recovers the program costs and lost contributions to fixed utility costs. (On a total customer basis, however, energy <u>bills</u> should be reduced because of the reduction in energy use.) Whereas <u>all</u> customers benefit from the demand savings (i.e., the kw savings) resulting from DSM program measures, participating customers are the primary beneficiaries of the energy savings. (At the same time, there is a benefit to the State as a whole, including non-participating customers, due to the reduction in the use of oil.) HECO Companies' Opening Brief at 62.

One of the primary justifications for the current approach to DSM programs is that there is a broad array of DSM measures available under the DSM programs, and a broad opportunity for customers to participate (and to directly benefit from bill savings). HECO Companies' Opening Brief at 62. In the case of CHP systems, all customers will benefit from the capacity deferral benefits that can be obtained from the installation, operation and maintenance of energy-efficient CHP systems, but only a relatively small number of customers have the opportunity to directly achieve energy cost savings through the installation of such systems on their sites. Thus, unlike the case with DSM programs, one of the key objectives of the CHP program is to avoid burdening non-participating customers. HECO Companies' Opening Brif at 63.

HREA-HECO-IR-13

On page 11, as a follow-up to HREA-HECO-IR-12, if all DG (including CHP) on the customer-side-of-the-meter were planned and implemented in IRP as DSM programs (as proposed by HREA on the DG docket), would not this mitigate HECO's concerns about competitively bidding these technologies? Consequently, we could focus in this docket on how to competitively procure wholesale power sources, including traditional central station generations and decentralized DG for delivery of wholesale power.

HECO Response:

It is inappropriate to consider DG as a DSM measure. Please see the response to HREA-HECO-IR-12.

HREA-HECO-IR-14

On page 12, first paragraph (see below), is there an alternative approach? For example, the PUC could prepare a draft Decision and Order for Hawaii's competitive bidding rules. All interested Parties could review and comment. Subsequently, the PUC could finalize a Decision and Order for Hawaii's competitive bidding rules.

> The details of the competitive bidding process should be developed in a follow up proceeding, based on the principles enunciated by the Commission in this proceeding. The HECO Companies prefer that the procedures be developed and adopted in a framework proceeding, like that used to develop the IRP Framework, rather than in a rulemaking proceeding.

HECO Response:

If HREA is proposing that the Commission develop "competitive bidding rules", then a rulemaking proceeding must be conducted pursuant to H.R.S. §91-3, which involves a public hearing and comment process. As the Companies stated in response to CA-IR-6, in contrast, a "framework proceeding" could be used to develop a set of competitive bidding guidelines, in the form of an enforceable Commission order. The result is similar to rules, but the procedures used to adopt the framework include an evidentiary hearing conducted pursuant to H.R.S. §91-9 to test the recommendations of the various parties to the proceeding, and an evidentiary record upon which the Commission can base a decision.

It will be difficult for the Commission to "prepare a draft Decision and Order" setting forth a framework for competitive bidding that could be reviewed and commented on by all interested parties. As the Companies stated in response to CA-IR-7, in order to establish a specific process for competitive bidding, a number of questions should be answered first. See Response to CA-IR-7.

In general, issuance of a proposed decision by an agency for comment is <u>not</u> a vehicle used to create a record upon which a decision can be made. See H.R.S. §91-11 for the purpose of issuing a proposed decision.

In essence, the Companies view a three-stage process - - in the first stage, basic guidelines are established; in the second stage, framework provisions (or agency rules) are established based on the guidelines; and in the third-stage, utility-specific provisions (RFP documents, process manuals, etc.) are developed in a manner consistent with the framework provisions (or rules). In the IRP framework proceeding, the first two stages were sequentially done in the same docket, because the parties were able to agree on guidelines for IRP in an initial stage of the docket.

HREA-HECO-IR-15

On page 13, as an alternative to the selection of a preferred approach in IRP based on the traditional evaluation from cost estimates, would HECO consider incorporating a bidding process (Model 2, as proposed by HREA in its PSOP, page 12), whereby proposals are selected for implementation in HECO's 5-year action plan?

HECO Response:

Model 2, as proposed by HREA, is overly simplistic and does not address the numerous issues with competitive bidding identified by HECO throughout its Statement of Position. Similar to its response in HREA-HECO-IR-11, HECO has a number of problems associated with Model 2 as a bidding process. While HREA has made some adjustments to the information required and specific requirements (i.e., Model 1 assumes a site has been identified by the utility while Model 2 does not assume a site has been identified; Model 2 also allows a utility to bid but not the utility) in the process relative to Model 1, Model 2 suffers from many of the same issues.

For example, instead of preparing a facility bidding baseline, Model 2 requires the utility to provide a target delivered wholesale cost of electricity. HECO is concerned by such a proposal to provide specific detailed cost data or estimated market prices to the bidders. Such disclosure could inhibit competition and limit the potential benefits of competitive bidding to encourage competition among bidders. The solicitation still envisions use of a standard offer contract. Please refer to the response to HREA-HECO-IR-11 for a discussion about the problems associated with the use of a standard offer contract for long-term resource options with potentially different characteristics. The Independent Contracting Agent (ICA) is responsible for soliciting and reviewing the bids, including the option for a utility affiliate to bid as an IPP. The ICA would be at even greater risk in this case since there is potentially no backstop resource as would be case if the host utility provides a project option.

HREA-HECO-IR-16

On pages 5 and 7 (Exhibit A), HECO questions whether PPAs with IPPs can be sufficiently flexible, and implies that HECO would therefore have a diminished capability to control its grid. Have there been any examples with existing IPPs where this has been the case? Please provide case studies as evidence.

HECO Response:

See the response to HREA-HECO-IR-9.

HREA-HECO-IR-17

On page 8, has there been any evidence in Hawaii to support HECO's claim that IPPs are more prone to "project failure and reliability concerns" than the utility? If there have been, were any of those projects deemed to be: (1) of high value to the utility, its ratepayers and the state, and (2) inherently risky such that the utility would have declined to pursue as utility-owned?

HECO Response:

Please note HECO believes HREA meant to refer to SOP Exhibit A, page 8.

Independent Power Producers ("IPPs") are incented to make a profit. It is generally believed that IPPs are willing to take the risk for project development and operations in return for the opportunity to earn a profit. IPPs have an obligation to perform according to the contract (i.e., power purchase agreement), but don't have an obligation to serve. Therefore, IPPs will follow economic incentives in making decisions regarding completion of a project, maintenance, and operations. The fact that the credit ratings of many IPPs are currently very low certainly adds to the risk of project failure and non-performance. See also the responses to HREA-HECO-IR-9 and HREA-HECO-IR-16.

HREA-HECO-IR-18

On page 8 (item 2), why does it necessarily take a long time to develop and implement a competitive bidding process? Can HECO recommend any ways to shorten the process?

HECO Response:

HECO assumes that the IR is referring to Exhibit A, page 8. Paragraphs one, two, and three of "item 2" explain why it can take a substantial amount of time to develop and implement a competitive bidding process. At this time, HECO does not have specific recommendations to "shorten the process", if the objective is to "take shortcuts". As explained on page 15 Exhibit A, it is important to invest the time up front:

> "The development and implementation of a competitive bidding process can be a very time consuming process, generally taking several years to complete. However, taking the time necessary to effectively develop the process in the early stages serves to avoid the potential for very costly mistakes and potential delays later in the process."

HECO does not agree that speed of process-development is more important than planning for success. It is irresponsible to disregard or discount the potential pitfalls. This concern was described on page 15 of Exhibit A:

> HECO has reservations about the effectiveness of competitive bidding in an island system such as Hawaii. If competitive bidding is implemented, there are a number of potential shortcomings or pitfalls that need to be addressed to ensure that a competitive bidding system provides benefits to customers and shareholders. HECO can appreciate some of the potential benefits of competitive bidding but supports the implementation of competitive bidding only if the process is designed in such a way that the benefits occur instead of the pitfalls.

HREA-HECO-IR-19

On page 9, HECO uses its next planned fossil increment (simple cycle peaking unit) on Oahu, Maalaea Unit M18 and Waena Unit 1 on Maui, and Keahole Unit ST-7 on Hawaii as examples to examine whether a competitive bidding process could be implemented in time to meet the anticipated need dates of 2009, 2006, 2010 and 2009 respectively. Given the development and implementation of the competitive bidding process as described by HECO, it does appear to be a challenge. See also HECO's discussion on Issue 2 (pages 15 to 7, Sections A and B.1).

As an alternative, HREA would like HECO to consider HREA's proposed Model 1 approach (pages 11 and 12 of our PSOP). Specifically:

1. HECO treats this exercise and the proposed alternative process as an opportunity for the company and its ratepayers,
2. For each project, the alternative processes would be considered pilot competitive bidding projects, which could provide valuable information for competitive bidding rules,
3. An independent observer would be retained by the PUC to monitor the bidding processes,
4. A Standard Offer Contract (SOC), tailored to the desired resource, is provided as part of the solicitation package (as a means to reduce the time to negotiate with a winning IPP proposal), and
5. Specific HECO concerns are addressed, e.g., permits obtained or in progress could be transferred to an IPP, rather than an IPP having to start from "scratch."

Given the above approach, and HECO started the competitive process immediately, could the anticipated in-service dates be met? If not, why not?

HECO Response:

HECO assumes that the IR is referring to SOP Exhibit A, page 9.

The HREA Models, as proposed, are not detailed enough to make an assessment at this time. HREA has not provided an estimated timeframe for further developing its model or for completing any of the major tasks or sub-tasks associated with the development of a competitive bidding process. Further, HECO has a number of problems with the Models as proposed, which are stated in the responses to HREA-HECO-IR-11 and -15. In addition, HECO's SOP, Exhibit

A, pages 34-40, describes the tasks that would need to be completed before a competitive bidding process can be initiated.

HREA-HECO-IR-20

On page 12, should the fourth column of the five column table be entitled "2006 – IPP Capacity as a Percent of Firm Capacity?"

HECO Response:

The table appears on page 12 of Exhibit A, and HECO confirms that the fourth column is incorrectly labeled. As the IR suggests, it should be "2006 – IPP Capacity as a Percent of Firm Capacity", instead of "2004 – IPP Capacity as a Percent of Firm Capacity", i.e., HECO used 2004 instead of 2006.

HREA-HECO-IR-21

On page 13, if the utility provides a "tolling option" for "gas" or other "fuels:"

1. How does that result in "absorbing the fuel risk?" It appears to HREA that tolling only transfers the risk to the utility, and
2. More importantly, is HECO prepared to propose any other alternatives that would really reduce the risk to the ratepayer? If so, how?

HECO Response:

HECO assumes that the IR is referring to SOP Exhibit A, page 13.

1. HECO's reference on page 13 to the utilities on the mainland absorbing the fuel risk through tolling pertains to fuel procurement risk only.
2. At this time, it is unclear to HECO that competitive bidding can reduce risks. As stated on page 15 of Exhibit A, HECO has concerns regarding competitive bidding:

   > "HECO has reservations about the effectiveness of competitive bidding in an island system such as Hawaii. If competitive bidding is implemented, there are a number of potential shortcomings or pitfalls that need to be addressed to ensure that a competitive bidding system provides benefits to customers and shareholders. HECO can appreciate some of the potential benefits of competitive bidding but supports the implementation of competitive bidding only if the process is designed in such a way that the benefits occur instead of the pitfalls."

HREA-HECO-IR-22

On page 13, fourth "bullet," did HECO conduct a parallel planning process while the county and developers were planning the HPOWER, Kalaeloa and AES facilities?

<u>HECO Response:</u>

HECO assumes that the IR is referring to SOP Exhibit A, page 13.

In 1987, HECO conducted parallel planning and engineering for a combined cycle unit addition as a contingency in the event AES-Barbers Point and Kalaeloa were not able to deliver firm power to HECO. HECO did not do parallel planning and engineering during the planning for the HPOWER facility. (Under the Firm Capacity Amendment, dated April 8, 1991, HECO agreed to purchase both energy and capacity from the City. Under the original purchased power contract dated March 10, 1986, HECO purchased energy from the City.) HECO did not have an immediate need for firm capacity from the HPOWER facility, due, in part, to the startup of the Kalaeloa facility earlier in 1991 and the planned 1992 in-service of the AES facility. However, HPOWER did allow for the deferral of future generation capacity additions.

HREA-HECO-IR-23

On pages 19 to 20, HECO discussed a second option to incorporate competitive bidding in IRP. HREA observes that this option is very similar to HREA's proposed Models 1 and 2, as one of the primary goals of all three approaches is to use competitive bidding as an input to develop the preferred IRP. Regarding HECO's concerns about the Option 2 as discussed:

1. If competitive bidding is used to select the resource options for the 5-year action plan, why does HECO assume that "developers may be unwilling to participate an early state in the process, or to freeze prices for the time required to complete the IRP process?"
2. Why does HECO assume that the bids would be "preliminary?" Why wouldn't the winning bids then proceed to a negotiations phase?
3. How does the utility measure the effectiveness of the Advisory Groups in IRP?
4. Regarding HECO's concerns about releasing confidential information to the Advisory Groups during the Option 2 bidding process, why not ask specific Advisory Group members be recused from deliberations, if there are perceived potential "conflicts of interest?"

<u>HECO Response:</u>

This response assumes that HREA is referring to pages 19 – 20 of Exhibit A of HECO's statement of position.

1. HECO expects that the time required for undertaking this Option would exceed the time for completing the bid evaluation and contract negotiation phase of Option 1 because of the lack of guidance to the bidder and the uncertainty associated with the products of choice. It has been the experience in other RFP processes that bidders prefer to hold their prices fixed for a short duration of time because of the risk associated with changes in equipment costs, inflationary impacts, technology changes, etc. that could have negative impacts on bidders relative to their price proposal. Therefore, HECO would expect bidders would respond in the same manner and such a process risks the possibility of fewer bids and less complete bids. The Option 2 process is more

consistent with a competitive negotiation process which is time and resource dependent.

2. With a longer process such as that expected under Option 2 and the uncertainty associated with the preferred products required by the utility, bidders would likely prefer to provide an "indicative bid" because of the risk of changing market conditions, regulatory uncertainty, confidentiality issues or other factors which could lead to revisions or delays to the IRP/competitive bidding process.

3. Although HECO maximizes public participation in its IRP, in part, through the use of an IRP Advisory Group, HECO does not explicitly measure the effectiveness of the IRP Advisory Group. The statement on page 20 "[s]uch an approach limits the effectiveness of the IRP Advisory Group , who are exposed to confidentiality issues and disclosure issues associated with potential access to competitive intelligence in the RFP process" was meant to mean that Option 2 would require confidential information to be utilized in the IRP process therefore the Advisory Group would have to be able to agree to disclosure restrictions (including excluding certain entities viewing information altogether) or excluding the Advisory Group altogether from access to the information. In either case, it would reduce the effectiveness of the Advisory Group compared to the current IRP process in which the meetings are open to the general public.

4. Recusing certain IRP Advisory Group members (and the general public) from Advisory Group meetings where confidential material is discussed is possible, but it also comes with its shortcomings. It reduces the openness of the IRP process (i.e. limits the effectiveness of the Advisory Group) compared to the current IRP process where the assumptions for generating resources used in the development of the IRP plan are provided to the entire Advisory Group for review and comment. There could also be

the issue of determining which Advisory Group member has a possible conflict of interest and whether organizations whose membership includes non-utility generators would be considered to have a possible conflict of interest.

HREA-HECO-IR-24

On page 22, HECO stated "It is possible that a utility self-build project – vetted through an RFP – could be the 'best deal for ratepayers'?" Would HECO agree that:

1. the utility would have to reach a conclusion about the cost-effectiveness of a self-build project after taking into account the impacts of rate-basing their investment,
2. there would be no pressure to increase rates due to an IPP proposal at or below avoided cost. In this case, does HECO believe they could self-build sufficiently lower than avoided cost to off-set the rate impacts from rate-basing the project, assuming a new Exhibit H from Docket No. 03-0366 based on HECO's new rate case,
3. if all bids were above current avoided cost (perhaps a more likely scenario), does HECO believe they could self-build sufficiently lower than all other bids in order to off-set the rate impacts from rate-basing the project?, and
4. please explain the effects of rate design and the impacts of gradually or immediately eliminating interclass and intraclass cross subsidies on your analyses in nos. 2 & 3, above.

<u>HECO Response:</u>

HECO assumes that the IR is referring to SOP Exhibit A, page 22.

1. Yes, evaluation of a utility self-build project would take into account the impacts of rate-basing the investment amongst other considerations as detailed in Exhibit A.
2. HECO has no idea what prices would be bid and how these prices may relate to the cost of the self-build option; however, it is also possible that either a new, large utility-built generation project or a new, large purchase power commitment will create pressure to increase rates. A large purchase power contract can create pressure to increase rates regardless of whether it is above or below avoided cost. For example, the Kalaeloa, AES, and HEP purchase power contracts were all deemed to be at or below avoided cost; however, rate cases were needed as a result of the capacity costs associated with each of the contracts (HECO 1990 test year rate case for Kalaeloa, HECO 1992 test

year rate case for AES, and HELCO 2000 test year rate case for HEP).

3. No, as discussed in (2), HECO has no idea what prices would be bid and how these prices may relate to the cost of the self-build option; however, both utility-built generation and purchase power can create pressure to increase rates. Further, the comparison of alternatives must take into consideration long-term cost impacts as well as other non-cost considerations as discussed in Exhibit A.

4. The issues of rate design and interclass and intraclass subsidies are not significantly impacted by competitive bidding.

HREA-HECO-IR-25

On page 23, item 4, if HECO were to pursue HREA's Model 1 approach for its next increment at Kahe on Oahu, wouldn't most of HECO's concerns in this section be mitigated? For example, if HECO solicited bids to meet or beat its projected performance, costs, and timeline for a simple cycle combustion turbine at the Kahe site, would not any transmission and system impacts be the same for both the company's bid and any bids in response to HECO's RFP?

<u>HECO Response:</u>

HECO assumes that the IR is referring to SOP Exhibit A, page 23.

See the response to HREA-HECO-IR-19.

HREA-HECO-IR-26

On page 24, third paragraph, please provide details supporting the following HECO statement:

> While recent accounting rules have affirmed how such costs should be treated, it is important to note that the *HECO Companies have already been required by the credit rating agencies to rebalance their capital structures as a result of their purchased power commitments.* The HECO Companies have had to add higher cost equity capital to balance the imputed debt attributed to existing non-utility power purchase agreements.

Specifically in addition to what is provided in Appendix C:

1. what was the effect on the capital structure and return sought in HECO's most recent rate case?, and
2. have there been any effects on HELCO's and MECO's capital structure and return, and if so, please quantify and provide spreadsheet backup of how these were or will be calculated?

<u>HECO Response:</u>

1. Financial ratio evaluations included in HECO's current rate case test year 2005 incorporate imputed debt of $247 million at the beginning of 2005 and $239 million at the end of 2005 for a test year average of $243 million. It also includes interest equivalent of $24 million. For the test year average, the debt/total capital ratio was 53% with imputed debt and 44% without imputed debt. (See HECO-2116 in Docket No. 04-0113.)

   The amount of rebalancing to try to maintain target financial ratios varies from period to period and over time; however, as of December 31, 2004, if HECO had no purchase power obligations, approximately $100 million less in equity would have resulted in the same equity ratio as the ratio it had with the imputed debt (45%). (See page 3.) Since equity investors require a higher return than debt holders, the increased amount of equity increases the cost of electricity to ratepayers.

   In addition to the increase in the equity investment balances, the purchase power obligations increase the expected rate of return on equity. HECO's Return on Equity witness in the current rate case, Dr. Roger Morin estimates that the impact of purchased power obligations on HECO's rate of return on equity is approximately 40 basis points. It increases the return requirement from 11.1% to 11.5%. (See HECO T-20 pages 59 to 63 in Docket No. 04-0113.) The increased rate of return expectations, in addition to the increased equity balances, increases the cost of purchase power contracts to ratepayers.

2. As of December 31, 2004, HELCO had imputed debt of approximately $42 million. The amount of rebalancing to try to maintain target financial ratios varies from period to period and over time; however, as of December 31, 2004, if HELCO had no purchase power obligations, approximately $20 million less in equity would have resulted in the same equity ratio as the ratio it had with the imputed debt (46%). In its last rate case, test year 2000, "substantial purchase power obligations" were among the risk factors cited by the Commission in determining that HELCO's rate of return on equity should be adjusted by 50 basis points.

As of December 31, 2004, MECO had imputed debt of approximately $1 million. Purchase power obligations at MECO have not been significant and as a result, have not impacted its rate of return on equity.

($ in thousands)

HECO (Oahu)	Book Balance as of 12/31/2004	Capital Structure Ratio per Book	Imputed Debt	Balance including Imputed Debt	Capital Structure Ratio w/ Imputed Debt	ILLUSTRATION ONLY: Estimated Rebalancing Adjustment	ILLUSTRATION ONLY: Capital Structure without Purchase Power	ILLUSTRATION ONLY: Capital Ratio
Short-term borrowings	61,460	5.16%		61,460	4%		61,460	5%
Long-term debt	436,503	36.65%	247,369	683,872	48%	100,000	536,503	45%
Hybrids	30,000	2.52%		30,000	2%		30,000	3%
Preferred stock	22,293	1.87%		22,293	2%		22,293	2%
Common equity	640,892	53.80%		640,892	**45%**	(100,000)	540,892	**45%**
	1,191,148	100.00%	247,369	1,438,517	100%		1,191,148	100%
HELCO (see p. 4)								
Short-term borrowings	34,850	9.70%		34,850	9%		34,850	10%
Long-term debt	120,908	33.65%	41,977	162,885	41%	20,000	140,908	39%
Hybrids	10,000	2.78%		10,000	2%		10,000	3%
Preferred stock	7,000	1.95%		7,000	2%		7,000	2%
Common equity	186,505	51.91%		186,505	**46%**	(20,000)	166,505	**46%**
	359,263	100.00%	41,977	401,240	100%		359,263	100%
MECO (Note 1)								
Short-term borrowings	(7,750)	-2.28%		(7,750)	-2%		(7,750)	-2%
Long-term debt	143,778	42.23%	1,399	145,177	42%	1,000	144,778	43%
Hybrids	10,000	2.94%		10,000	3%		10,000	3%
Preferred stock	5,000	1.47%		5,000	1%		5,000	1%
Common equity	189,413	55.64%		189,413	**55%**	(1,000)	188,413	**55%**
	340,441	100.00%	1,399	341,840	100%		340,441	100%
HECO CONSOLIDATED								
Short-term borrowings	88,560	4.68%	-	88,560	4%		88,560	5%
Long-term debt	701,189	37.08%	290,745	991,934	45%	121,000	822,189	43%
Hybrids	50,000	2.64%	-	50,000	2%		50,000	3%
Preferred stock	34,293	1.81%	-	34,293	2%		34,293	2%
Common equity	1,016,810	53.78%	-	1,016,810	**47%**	(121,000)	895,810	**47%**
	1,890,852	100.00%	290,745	2,181,597	100%		1,890,852	100%

Note 1: MECO's imputed debt at 12/31/04 relates to the HC&S purchase power agreement which will expire on 12/31/07.

Hawaii Electric Light Company.
2004 Purchase Power Credit Impact Using the Standard & Poors Method
Debt Equivalent ($000)

	A	B
	Debt Eqivalent End of Year 2004	Interest Equivalent (A x 10%)
PGV (p. 5)	12,158	1,216
Hamakua (p. 6)	29,819	2,982
Total	41,977	4,198

S&P Risk Factor of	30%
Interest Equivalent at	10%

PGV
Credit Impact Using the Standard & Poors Method
($000's)

S&P Risk Factor of	30%
Interest Equivalent at	10%

Annual Capacity Payment [1]	4,505
Monthly Capacity Payment [2]	375
End Month of Capacity Payments	Dec-27

		A Present Value Remaining Pmts	B Risk Factor	C = A x B Debt Equivalent
Balance at	12/31/2004	40,526	30%	12,158

[1] Based on $4,000,000 for 25 MW and $504,750 for additional 5 MW.

[2] Monthly payments made in arrears.

Hamakua
Credit Impact Using the Standard & Poors Method
($000's)

S&P Risk Factor of	30%
Interest Equivalent at	10%

Annual Capacity Payment [1]	10,739
Monthly Capacity Payment [2]	895
End Month of Capacity Payments	Dec-30

		A	B	C = A x B
		Present Value Remaining Pmts	Risk Factor	Debt Equivalent
Balance at	12/31/2004	99,397	30%	29,819

[1] Based on $15.43/kw-month for 58 MW.

[2] Monthly payments made in arrears.

HREA-HECO-IR-27

On page 25, HECO notes the following at the top of the page:

> The Wisconsin Public Service Commission concluded that the *utility must be compensated for the adverse impact on its capitalization associated with capital lease obligations arising from purchased power transactions.*

HECO appears to imply here, that HECO should be treated the same as utilities in Wisconsin, and be compensated if HECO is required to secure additional equity to counterbalance the increased debt due to the acquisition of additional purchase power.

As an alternative, HREA would like HECO to contrast its potential situation with that of a T&D company in a restructured market. For example:

1. Since the T&D company, or separate Transcos and Distcos, purchase all of their purchases all of its power, how does the argument of "debt/equity" come into play, and

2. With respect to purchasing power, how is the T&D company, or Transco and Distco conceptually different from a public utility, such as HECO, that also purchases power?

<u>HECO Response:</u>

HECO assumes that the IR is referring to SOP Exhibit A, page 25.

1. IOU's that are T&D companies (companies who have sold or divested their generation) have the obligation to deliver power on behalf of customers. Either the customer buys the power from a marketer and the T&D delivers the power or if the customer opts not to purchase power from a competitive supplier, the utility acquires standard offer or default service on a short-term basis. In most if not all the cases, the supplier bears the risk if customers migrate to the competitive marketplace. The T&D does not bear the long-term risk unlike a fully integrated utility that has the long-term obligation to serve and must secure generation service or build resources to meet this obligation. In an island-utility situation, the utility must rely on the limited independent power producers to meet operational needs, therefore there is a need to enter into long-term

commitments. The independent power producers need assurance that they will be paid for their fixed investments and the utility needs assurance that the capacity will be available at a reasonable rate; therefore generally, fixed-price capacity arrangements are entered into. From the utility standpoint, long-term, fixed price purchase power arrangements are considered debt or result in imputed debt. Conversely, short-term contracts or contracts with market price adjustments are less likely to be considered debt or result in imputed debt.

2. See the response to part (1).

HREA-HECO-IR-28

On page 26, HECO presents a hypothetical case of an IPP that sells power to a utility over a long period (e.g., 30 years), retires its debt, but keeps selling power to the utility. Since the IPP is not subject to the same requirements as a regulated utility, HECO appears to suggest that the IPP might make extraordinary profits, or at least profits that would exceed those for a public utility during the same project during the projects "end game". Consequently, the implied argument is that the ratepayers would be harmed. HREA is not sure this would be the case in Hawaii. For example:

1. Under current law in Hawaii, the power purchase price would be avoided cost or less, or, in a competitive bidding process, whatever price for a winning bid turns out to be. Either way, the price would, presumably, be less than the utility bid (assumes the IPP wins), which would provide benefits to ratepayer. So if the winning price was good for the first 30 years, and the contract was extended another 10 years, how could it not still be a good price?

2. If the utility was concerned about the possibility of some harm to the ratepaywer, could not the utility pre-negotiate a price for the post-contract period, e.g., the price is X for the first 30 years, then 0.8X for the next 10 years?

<u>HECO Response:</u>

HECO assumes that the IR is referring to SOP Exhibit A, page 26.

1. In the hypothetical situation presented, if the contract was extended, the price for the extension would be based on avoided costs or other utility options at the time the extension is negotiated.

2. Pre-negotiating a price for an extension of the contract beyond the contract period at the buyer's option is among the options HECO would consider.

HREA-HECO-IR-29

Ref: HECO Companies SOP, Page 29-34 of Exhibit A.

On pages 29 to 34, HECO provides a response to Issue 2a: How can a fair competitive bidding system be developed that ensures that competitive benefits result from the system and ratepayers are not placed at undue risk? This response, including a discussion of lessons learned (pages 32 to 34) appears to be based primarily on a competitive bidding process as envisioned by HECO, and an assessment of problems that appear to HREA to have occurred on the mainland, e.g. items 2 on page 32 and 9 on page 33:

Consequently, HREA questions how many of these and other HECO concerns:

1. Really apply to Hawaii?
2. Apply to firm capacity as currently proposed for HECO self-build vs. other capacity needs?
3. Can be mitigated by applying HREA's proposed Model 1 for those projects currently proposed for HECO self-build?

HECO Response:

HECO assumes that the IR is referring to SOP Exhibit A, pages 29 to 34. Please note that this IR does not appear to be asking any questions. However, HECO has commented on HREA's comments.

1. All the lessons learned and characteristics of successful competitive bidding processes identified are applicable to Hawaii. In fact, the two items identified by HREA (item 2 and item 9) are particularly relevant and extend beyond state bounds. The credit quality of the counter-party is certainly not "region or state based" but is pertinent to the specific bidder. If bidders with low credit quality submit proposals it is irrelevant what state they are bidding into. Thus, HECO as every other utility soliciting power supplies has to be concerned about the poor credit quality of potential counter-parties. In fact, some of the largest power project developers fall into the poor credit quality category.

Item 9 is also of particular importance. Again, this item pertains to the poor financial conditions of the counterparty, a situation that will not be alleviated even if the power generator is submitting a proposal in Hawaii.

2. The discussion presented on pages 29 to 34 addresses firm capacity, since this is the product most frequently solicited through the RFP process envisioned.

3. HREA's Model 1 does not address any of HECO's concerns, as presented on pages 29-34. Model 1 is a very general overall process that is short on the specific details. Furthermore, HECO has provided examples of the problems with the application of HREA's Model 1 approach (see HECO's response to HREA-HECO-IR-11) for solicitation of and evaluation of power supply options. HECO also disagrees with HREA's position that an Independent Contracting Agent should be retained to solicit and review bids from independent power producers and recommend project award. HECO's concerns will not be mitigated by Model 1 because HECO does not envision a scenario whereby the proposed Independent Contracting Agent will be legally responsible to HECO and its customers if its selection results in unreliable or higher cost supply options.

HREA-HECO-IR-30

From HREA's perspective, perhaps the most important issue NOT discussed in HECO's PSOP is the issue of fuel price/volatility and supply risks for conventional central station generators and any utility-owned CHP and additional supply-side DG, should that be approved. This leads to the following questions:

1. Is HECO proposing that the PUC approve the continued use of long-standing "energy cost adjustment clause" (ECAC)?
2. If so, what is the justification?
3. Is HECO willing to share the fuel risks with ratepayers?
4. If so, how would HECO propose to share fuel price risk with ratepayers?

HECO Response:

1. Rate schedules for the HECO utilities include an automatic adjustment clause known as the energy cost adjustment clause (ECAC). The ECAC is defined as a provision in the utility's rate schedule that provides for increases or decreases (or both) in rates reflecting increases or decreases (or both) in costs incurred by a utility for fuel and purchased energy due to changes in the unit cost of fuel and purchased energy. See Decision & Order No. 18365 ("D&O 18365") in Docket 99-0207, pages 39-40. The purpose of the ECAC is to address the volatility of the fuel and purchased power markets, and to accommodate changes to the generation and purchased energy mix percentages without the need for a new rate case. D&O 18365 in Docket 99-0207, page 42. HECO is not asking the PUC to re-approve the ECAC as a part of this docket. The ECAC is discussed in HECO filings in Docket No. 04-0113 (HECO's 2005 Test Year Rate Case). A copy of those filings is attached as pages 3-24 of this response.
2. Not applicable.
3. As described in subpart one, ratepayers realize both risks and benefits with ECAC.

4. At this time, HECO is not proposing any alternatives to ECAC. The Commission has found that the ECAC, in its current form, is reasonable. D&O 18365 in Docket No. 99-0207, page 43.

HECO ~~T~~-1
DOCKET NO. 04-0113

TESTIMONY OF
ROBERT A. ALM

SENIOR VICE PRESIDENT
PUBLIC AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Introductory Statement

A. The requested revenue increase is being allocated as an equal percentage increase to each rate schedule. This departs from past revenue increase allocations, where HECO proposed to allocate the revenue increase to rate schedules, such that the rates moved closer to the cost to serve the rate schedule.

Q. Why has HECO departed from its past revenue increase allocations?

A. After extensive discussion and examination, while the rates should reflect the cost to provide the service, the rate increase impact to customers must also be considered. Based on the $98,614,000 or 9.9% increase, the rate increase to the residential customer would be approximately 15%, based on HECO's criteria that the allocation to the rate schedule should be plus or minus 25% of the system increase, and the class rate of return should be between plus or minus 50% of the system rate of return. Considering the relatively high electric bills for residential customers due to the current fuel prices, an increase of 15% may be difficult for residential customers. Thus, HECO is proposing to allocate the revenue increase to all rate schedules equally to share the burden among all rate-payers. At the same time, if the amount of HECO's final revenue increase approved by the Commission is less than the amount requested in this application, the Commission should consider HECO's past criteria for the revenue increase allocation in making its final revenue allocation.

Energy Cost Adjustment Clause

Q. What is the Energy Cost Adjustment Clause?

A. The Energy Cost Adjustment Clause ("ECAC") is a provision in HECO's rate schedules that allows it to apply a factor (in terms of cents per kilowatthour) that increases or decreases charges to reflect fluctuations in fuel prices and purchased energy expenses above or below levels included in base rates. (See HECO-105, page 31 for HECO's ECAC.)

Q. Why does your testimony address the continued need for an ECAC?

A. At the end of 1997, HECO received Commission approval of the current fuel contracts with 7-year terms in Docket Nos. 97-0396 and 97-0397. This led the Commission to question whether continuation of an ECAC is necessary "...in light of the length of the contracts and the stability of fuel prices..." (See Decision and Order No. 16141 ("D&O 14141 dated December 30, 1997, pages 3-4 and Decision and Order No. 16142 ("D&O 16142") dated December 30, 1997, page 4.) (Amendments to the contracts to extend the contracts for an additional ten years on substantially the same terms and conditions were executed in March and April 2004 and applications for approval of the amendments were submitted to the Commission in Docket Nos. 04-0128 and 04-0129 filed on May 28. 2004.)

In D&O Nos. 16141 and 16142, the Commission indicated that it intended to investigate the question either in a generic docket or in each Applicant's next rate case.

Q. Was the question of continuing the ECAC addressed in subsequent rate case filings?

A. Yes, it was addressed in MECO T-1, T-15 and T-16 in MECO's application filed January 9, 1998 in Docket No. 97-0346, and in HELCO T-1, T-16 and T-17 in HELCO's application filed October 25, 1999 in Docket No. 99-0207. The Consumer Advocate's recommendations and the Commission's final decision in Docket Nos. 97-0346 and 99-0207 took into account continuation of the ECAC.

HECO's testimonies in this docket (HECO T-1, T-10, T-20 and T-21) again address the reasons for continuing the ECAC in order to ensure that HECO has adequately responded to D&O 16141 and D&O 16142 in its "next" rate case.

Q. In light of the length of the current fuel contracts, and amendments to extend the contract for an additional ten years, does HECO need an ECAC?

A. Yes. While the 7-year length of the current contract and the amendments to continue the contracts for an additional ten year period under substantially the same terms and conditions, are appreciably longer than the 2-year contracts entered into previously, fuel prices under the contracts cannot be considered to be "stable".

Q. Why can't fuel prices be considered to be "stable" under HECO's fuel contracts?

A. Fuel prices under the current contracts, and under the amendments which are currently before the commission, like the fuel prices under prior contracts, are directly tied to various international and domestic fuel price indices. Therefore, HECO's fuel prices will continue to vary based on fluctuations in international and domestic indices, which are strongly influenced by global oil prices. One advantage of a 7-year term (and the amended contract for an additional ten years) is that certain adders to the base (indexed) oil prices have now been determined for the terms of the contracts (which will make the affected adders more "stable"). However, this will not "stabilize" overall fuel prices, the bulk of which fluctuate with changes in the fuel price indices referenced in the contracts. The fuel price formulas are confidential, and were filed under Protective Order No. 16095 (November 21, 1997) in Docket No. 97-0396 and Protective Order No. 16096 in Docket No. 97-0397 and under Protective Order No. 21061 in Docket No. 94-0128 and Protective Order No. 21062 in Docket No. 940129.

Q. Why does HECO need an ECAC?

A. Under the contracts and contract amendments, fuel prices can still vary significantly with changes in the price of crude oil. HECO units that provide firm capacity are 100% oil-fired. Thus, one of HECO's largest expenses, its fuel expense, will fluctuate with the price of crude oil. Further, since a substantial portion of HECO's purchased energy payment rates (which are based on HECO's quarterly filed avoided energy costs) are tied to current fuel prices, HECO's purchased energy expense will also fluctuate with the price of oil. Continued use of an ECAC is the most reasonable means of fairly compensating HECO for its fuel and purchased power expense, without unreasonably penalizing either HECO or its customers.

Q. What would be the effect of the elimination of the ECAC?

A. In very general terms, if the ECAC were eliminated, it is likely that:

1) HECO's base rates would be set at a level that included fuel and purchased energy expense based on fuel prices determined at either (a) the point in time the Company submitted its rebuttal position (presuming this is the last set of calculations submitted by a party in a rate case) <u>or</u> (b) at the time the Commission renders its decision in a rate case. (The determination of test year fuel prices would become a critical, time-consuming issue in each rate case.)

2) When fuel prices rise above the levels incorporated in base rates, HECO would absorb the additional expense resulting from the price increase up to the time base rates are raised in the next general rate case.

If fuel prices are above those in base rates, customers might "enjoy" lower fuel-related charges in the short run. However, since fuel and purchased energy expense is more than 55% of HECO's test year O&M expenses, HECO's financial integrity would likely be significantly compromised.

3) When fuel prices are below the levels included in base rates, HECO customers would be charged more than HECO would be then paying for fuel.

Based on past history, fuel prices may well fluctuate both above and below the levels included in base rates. In such a case, HECO and its customers would correspondingly oscillate between points 2) and 3) described above. As a result of the significant financial risk exposure related to fluctuations in the price of fuel, HECO, as well as the other electric utilities in Hawaii, might require continual ratemaking proceedings before the Commission to maintain a reasonable rate of return.

In addition, elimination of the ECAC would have a major effect on HECO's business risk, and therefore increase its requisite cost of equity. Dr. Morin includes a brief discussion of this effect in HECO T-20.

Q. How have fuel prices varied from base rate levels in recent years?

A. Fluctuations in fuel price can be gauged by the amount of revenues collected through the ECAC. Since 1995, HECO has recovered on an annual basis between $2 million and $181 million through its ECAC. (See HECO-WP-150.) HECO cannot reasonably be expected to absorb an additional $181 million expense in a single year. Similarly, it would be unfair to HECO customers if HECO "over-collected" and "kept" any revenues above amounts that were intended to simply cover fuel and purchased power expenses. It is unreasonable to leave the matter of whether HECO "loses" or customers "lose" to the vagaries of fuel prices.

Q. Is the current ECAC fair to HECO customers?

A. Yes. The ECAC is negative when fuel prices are below the level included in base rates, and it is positive when fuel prices are above levels included in base rates. Further, current practice provides for a quarterly reconciliation of revenues collected through the ECAC and fuel and purchased energy expenses. (See HECO-105, page 31 for the reconciliation provision in the ECAC.)

Q. Are HECO customers "harmed" if the ECAC is continued?

A. For the reasons stated above, no.

Q. Would elimination of the ECAC give HECO an incentive to seek out more "favorable" fuel contracts?

A. No. HECO does not need an additional incentive to pursue favorable fuel contracts. HECO has amply demonstrated that it will aggressively pursue the best fuel contracts possible. However, elimination of the ECAC might necessitate that HECO attempt to "stabilize" its oil prices through hedging arrangements (in order to maintain its financial integrity and credit rating), which would increase the price of energy to its customers (due to the cost of the hedging arrangements).

Q. You indicated that HECO has requested approval of fuel contract amendments to extend the contracts for 10 years on substantially the same terms and conditions. What positions have the Consumer Advocate taken with respect to the amendments and the ECAC?

A. The Consumer Advocate indicated in its Statements of Position filed on November 8, 2004 in Docket Nos. 04-0128 and 04-0129 that (1) the 10-year extension of the contracts is reasonable; (2) use of the ECAC to protect against significant changes in the prices of fuel benefits both the Company and its customers; (3) HECO's "use of the ECAC to address the changing price of fuel does not appear to have diminished its effort in research and utilization of renewable energy." The Consumer Advocate concluded that continued used of the ECAC by the Company is reasonable at this time.

HECO T-10
DOCKET NO. 04-0113

TESTIMONY OF
ALAN K.C. HEE

MANAGER
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Customer Service Expense,
Demand-Side Management Program Expense,
Integrated Resource Planning Expense,
Energy Cost Adjustment Clause

continue for another 12 calendar months after the effective date of the rate case D&O in order to recover the incremental IRP planning costs incurred through the effective date of the rate case D&O.

In addition, The Commission has not issued a final D&O approving the recovery of 1995-2005 IRP Planning Costs. The difference between IRP Planning Costs already recovered and the amount approved in the Commission's final D&O will be reconciled over a period of 12 calendar months through the IRP adjustment component of the IRP Clause.

ENERGY COST ADJUSTMENT CLAUSE

Q. What is the test year Energy Cost Adjustment ("ECA") factor at current and proposed rates?

A. The test year ECA factor is 2.586 ¢/kWh at current rates, and 0.000 ¢/kWh at proposed rates as shown in HECO-1030.

Q. What is the Energy Cost Adjustment Clause ("ECAC")?

A. The ECAC is an automatic adjustment provision in the utility's rate schedules that allows the utility to automatically increase or decrease charges to reflect the change in the Company's energy costs of fuel, CHP energy and purchased energy above or below the levels included in the base charges without a rate proceeding. The Company's current base fuel energy charges and fixed efficiency factor embedded in the base charges, shown in HECO-1031, were established in the last HECO rate case, Docket No. 7766.

Q. What is the purpose of ECAC?

A. The purpose of ECAC is (1) to address price changes in the Company's cost of fuel and purchased energy and (2) to accommodate changes to the generation, CHP and purchased energy mix percentages, without the need for a rate case.

Q. How does ECAC work?

A. A rate case proceeding determines the base electricity rates into which are embedded test year levels of fuel prices, payment rates for purchased energy and a test year resource mix. The ECAC mechanism, expressed in cents per kilowatt-hour, allows the Company to recover costs due to subsequent changes in (1) fuel and purchased energy costs, (2) the resource mix between utility-owned generation, utility-CHP and purchased energy, (3) the resource mix among the utility plants, and (4) the resource mix among purchased energy producers. A rate case proceeding also establishes a fixed efficiency factor, or sales heat rate, for the utility central station generation to incentivize operation of the units as efficiently as possible. An ECA factor, which sets the rate adjustment that reflects these changes for the coming month, is filed with the Commission monthly.

Q. How does the PUC exert its overview of the costs passed through the ECAC?

A. All costs that pass through the ECAC must result from fuel oil and purchased energy contracts and/or agreements that have been approved by the Commission.

Q. Why does the Company need the ECAC?

A. The Company needs the ECAC because fuel costs are a large portion of its expenses and because fuel price levels are largely beyond the Company's control.

In the test year, fuel and purchased energy expenses make up over 55% of total O&M expenses. This makes the Company's financial condition susceptible to changes in fuel prices. The ECAC benefits the Company and its shareholders by:

- Limiting the swings in cash flow and earnings,
- Reducing the cost of capital,

- Improving the Company's ability to earn a fair return on investor capital, and;
- Providing a more timely recovery of fuel and purchased energy costs.

Q. How does the ECAC benefit customers?

A. The ECAC benefits customers by:

- Reducing the Company's financial risk and lowering the cost of capital. The resulting savings are passed on to our customers through lower base rates in rate proceedings such as this one.
- Passing through to customers, the savings incurred when fuel prices fall below the prices embedded in base rates, to the same extent that they will incur additional costs when fuel prices are above the embedded fuel prices.

Q. How much have customers saved because of the ECAC?

A. Between January 1984 and September 2004 HECO's ECAC has returned more than $273 million to our customers.

Q. What other benefits does the ECAC have?

A. Since the ECAC is an automatic clause it allows the Commission time to concentrate on other key, substantive strategic issues.

Q. How are the ECA factors computed?

A. The ECA factors are equal to the difference between test year energy costs and base composite costs. At present rates the base composite costs are those established in the last rate case. At proposed rates the base composite costs are based on the test year fuel price, including trucking and inspection costs, the fuel resource mix (based on the test year fuel consumption), test year CHP energy expense, test year purchased energy expense, and test year fuel efficiency. Computation of the ECA factors, at present and proposed rates, is similar to the monthly factor computation filed with the Commission, as shown in HECO-1032.

Q. With respect to Kalaeloa and AES Hawaii, what is included in the ECAC?

A. For both current and proposed rates, only the fuel and fuel additive components of Kalaeloa's energy charge and the fuel component of AES Hawaii's energy charge are included in the ECAC.

Q. Why are the ECA factors different at current and proposed rates?

A. There are two reasons for the difference. First, the base fuel cost, base CHP energy cost and base purchased energy cost at proposed rates have been changed to reflect the test year composite costs for fuel, CHP energy and purchased energy. Second, the fuel efficiency factor (the sales heat rate) used to calculate the base generation component cost has been revised to reflect the test year fuel efficiency. The current rates include the composite costs for fuel and purchased energy and the fuel efficiency factor established in the last HECO rate case, Docket No. 7766.

Q. Do the ECA factors at current and proposed rates include the CHP component that was introduced by the Company in Docket No. 03-0366?

A. Yes, it does.

Q. Why is the Company proposing to include the CHP component?

A. The CHP component allows the Company to recover the fuel, transportation costs, and related revenue taxes, incurred under the utility's CHP agreements to the extent that the costs are not recovered in the Company's base charges.

Q. If the Company's CHP installations are utility-owned generators why are they treated differently from the Company's other utility-owned generators?

A. CHP units are generally more efficient than other Company-owned generating units and would tend to improve system efficiency and lower the system heat rate.

The Company has indicated that it intends to install an increasing number of CHP units. As more utility CHP units are installed the system heat rate will continue to improve.

Separating the Company's CHP generation from the Company's other utility-owned generation in the ECA factor calculation will allow the benefits of CHP units' improved efficiency to pass through the ECAC to our customers. If the utility-owned CHP generation were included with the Company's other utility owned generation, the resulting efficiency factor would be fixed in base rates. However, as the number of CHP units increase over time, the actual system heat rate would improve. With the CHP generation included in the fixed efficiency factor, the heat rate improvements would not be passed through to the customers.

Q. How does the CHP component allow ratepayers to benefit from the improved efficiency resulting from the installation of utility-owned CHP?

A. The CHP component would recover CHP fuel and transportation costs at actual expense levels and would not be subject to the fixed efficiency factor. To the extent that CHP unit heat rates are better than the fixed efficiency factor, the actual CHP efficiency will pass through the ECAC.

Q. How are the avoided energy cost rates and Schedule Q rates for Qualifying Facilities < 100 kW determined?

A. The Company uses the proxy method in its calculations of the avoided cost rates and Schedule Q rates. The calculations incorporate a factor equal to their composite fuel costs, which is applied to certain proxy heat rates. The composite fuel costs include the fuel and transportation costs for all company-owned generation.

Q. Are the calculations of avoided energy cost and Schedule Q modified due to the inclusion of the CHP component in ECAC?

A. Yes. The avoided energy cost rates and Schedule Q payment rate incorporates the CHP component in the composite fuel cost, as proposed in Docket No. 03-0366.

Q. What modifications were made to the calculations of avoided energy cost and Schedule Q?

A. The composite fuel cost of total generation is a weighted composite cost, based on the central station energy component and the company owned CHP energy component.

<u>2003 ACTUAL EXPENSES VS. 2005 O&M EXPENSE BUDGET</u>

Q. What are the differences, greater than $200,000, between 2003 actual expenses and the 2005 O&M Expense Budget?

A. Most of the differences relate to expenses for the new and enhanced energy efficiency and load management DSM programs that are discussed earlier in my testimony. These differences are detailed further in HECO-WP-1033.

Q. Does this conclude your testimony?

A. Yes, it does.

HECO T-20
DOCKET NO. 04-0113

TESTIMONY OF
ROGER A. MORIN, Ph.D.

ON BEHALF OF

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate of Return on Common Equity normally added based on requirements to serve existing customer loads and not new customer loads. They are also costly, reduce generation plant efficiencies, and raise issues concerning efficiency of operations.

Because of the Company's predominantly oil-based generating capacity, a dominant element of business risk peculiar to HECO is a significant reliance on fuel oil and the potential risks associated with variations in the price of oil. To illustrate, the fuel cost per barrel increased from $29 to $36 from 2002 to 2003. Mitigating this aspect of HECO's business risk is the Commission's continuation of a favorable energy cost adjustment clause, decreasing the Company's risk of not recovering its substantial fuel costs.

Q. Dr. Morin, can you please comment on the impact of the commission's energy cost adjustment clause on the Company's business risk?

A. Yes, certainly. The Energy Cost Adjustment Clause ("ECAC") serves to reimburse HECO for prudently-incurred energy costs in a manner that minimizes the negative financial effects caused by regulatory lag. Consideration of energy costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed. To illustrate, it is my understanding that bond rating agencies would place considerably more weight on the Company's purchased power contracts as debt equivalents in the absence of ECAC, thus weakening the Company's financial integrity. The ECAC mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection is factored into the Company's credit profile as a negative element which in turn raises its cost of capital, as discussed above.

The approval of energy cost recovery mechanisms by regulatory commissions is widespread in the utility business. Approval of fuel adjustment clauses, purchased water adjustment clauses, and purchased gas adjustment clauses has become widespread. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy.

I believe that in the absence of the Commission renewal of the ECAC requested by HECO in this proceeding, HECO's financial condition would deteriorate, its credit ratings would likely be under review for possible downgrade, and its customers would be at risk of having to pay higher rates due to access to capital becoming more expensive for HECO. This situation would have a substantial effect on HECO and its customers because of the magnitude of the energy cost component in its cost of service.

Recovery of prudently incurred costs expended on energy allows a regulated utility to serve its native load customers in a reliable manner while maintaining its financial integrity or strength. Since the cost of energy is both a significant component of HECO's operations as well as variable over time, debt and equity investors consider the risks underlying these factors in their determinations as to whether to provide funding and upon what terms within a particular jurisdiction.

I encourage the Commission to renew HECO's ECAC, and I believe that approval of HECO's request for continued approval of its ECAC is fair to HECO, its customers, and investors. I believe that the ECAC deals with the cost of fuel and purchased energy, as well as with the mix of resources, which can vary month-to-month and which can represent a considerable financial outlay, on a consistent basis, without need for recurring regulatory proceedings that are time-consuming, costly, and, significantly, create uncertainty within the financial community.

Q. What is the net effect of these business risk factors on the Company's risk profile?

A. The net effect of all these business risk factors is that HECO's business risks slightly exceed those of U.S. electric utilities. This is corroborated by the Company's Standard & Poor Business Risk Score of 6.0 on a scale of 1.0 to 10.0 with 1.0 being the least risky and 10.0 the most risky.

Q. Please comment on HECO's regulatory risks.

A. An important component of risk for utilities is "regulatory risk". The regulatory framework in which a utility operates is a pivotal aspect of risk from the investors' perspective. The investment community is very conscious of the regulatory environment, as evidenced in the reports of both bond rating agencies and investment analysts. Regulatory risk generally refers to the quality and consistency of regulation applied to a given regulated utility and specifically to the fairness and reasonableness of regulatory decisions. By allowing returns that are inconsistent with informed investors' risk perceptions, or by disallowing prudently incurred costs and capital investments, or by approving rate designs that are insufficient to recover fixed costs, or by allowing capital structures that are inconsistent with business risks and out of line with those of comparable risk utilities, regulation can certainly expose utilities to enormous risks. Other determinants of regulatory risk include specific policy parameters such as the average regulatory lag inherent in regulatory procedures in a given jurisdiction, the use of forward vs. historical test years, and whether the utility has the

HECO T-21
DOCKET NO. 04-0113

TESTIMONY OF
RICHARD A. VON GNECHTEN

ON BEHALF OF

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate of Return on Rate Base

This rate case will be a significant indicator of the regulatory environment in which HECO does business. Key considerations include: timely and adequate rate relief, adequate return on equity, treatment of demand-side management ("DSM") programs, and recovery of fuel and purchased-power costs.

5. Fuel oil supply and importance of energy cost adjustment clause

Though the Company has undertaken many efforts to diversify its fuel source, a major portion of the electricity is generated from oil-fired power plants. Substantial reliance on a single source of fuel makes the Company vulnerable to changes in supply and price of that resource.

The current energy cost adjustment clause ("ECAC") mechanism substantially reduces the Company's risk with regard to fuel oil prices. Changes to the ECAC could significantly impact the Company's ability to recover fuel oil costs and the purchase power energy costs incurred under long term power purchase agreements ("PPAs"). The ECAC also ensures that the utility's customers benefit from falling fuel oil and purchase power costs. Investors view the ECAC as a means to substantially reduce HECO's risk of fuel oil and purchase power reliance. Continuation of the ECAC is vital to maintaining stable earnings potential and financial strength.

6. Hawaii economy

The Company's operating results are significantly influenced by the strength of Hawaii's economy. Tourism, the largest component of Hawaii's economy, is susceptible to rapid deterioration (for example, resulting from terrorist acts, the geopolitical and war situation and airline labor strikes).

DOD/HECO-IR-3-14

[Morin Direct, p. 4, ll. 19-22]

Please provide a narrative description of Dr. Morin's understanding of the "Company's current energy cost adjustment clause," and how elimination of that adjustment clause would impact the Company's risk compared to other electric utilities that do not have such an adjustment clause.

Dr. Morin's Response:

Because of the Company's predominantly oil-based generating capacity, a dominant element of business risk peculiar to HECO is a significant consumption of fuel oil and the potential risks associated with variations in the price of oil. To illustrate, the fuel cost per barrel increased from $29 to $36 from 2002 to 2003. Mitigating this aspect of HECO's business risk is the Commission's continuation of an energy cost adjustment clause, decreasing the Company's risk of not recovering its substantial fuel costs.

The Energy Cost Adjustment Clause ("ECAC") serves to reimburse HECO for prudently-incurred energy costs in a manner that minimizes the negative financial effects caused by regulatory lag. Consideration of energy costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed. To illustrate, it is my understanding that bond rating agencies would place considerably more weight on the Company's purchased power contracts as debt equivalents in the absence of ECAC, thus weakening the Company's financial integrity. The ECAC mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection would be factored into the Company's credit profile as a negative element which would in turn raises its cost of capital, as discussed above.

In the absence of the Commission renewal of the ECAC requested by HECO in this proceeding, HECO's financial condition would deteriorate, its credit ratings would likely be under review for possible downgrade, and its customers would be at risk of having to pay higher rates due to access to capital becoming more expensive for HECO. This situation would have a substantial effect on HECO and its customers because of the magnitude of the energy cost component in its cost of service.

Recovery of prudently incurred costs expended on energy allows a regulated utility to serve its native load customers in a reliable manner while maintaining its financial integrity or strength. Since the cost of energy is both a significant component of HECO's operations as well as variable over time, debt and equity investors consider the risks underlying these factors in their determinations as to whether to provide funding and upon what terms to a particular company.

HREA-HECO-IR-31

During the proceedings on the original competition docket (No. 96-0493), HECO indicated support for competitive bidding on new generation. Has that position changed? If so, how?

<u>HECO Response:</u>

On pages 115 through 118 of HECO's Final Statement of Position in Docket No. 96-0493, filed October 16, 1998, HECO described a number of advantages and disadvantages associated with competitive bidding. In particular, HECO urged caution on page 117:

> "The potential advantages and disadvantages of bidding have to be recognized and addressed when developing the process to ensure that all parties benefit from the advantages and do not suffer from the disadvantages"

This cautionary tone regarding competitive bidding is generally consistent with HECO's SOP in this docket. In the nearly seven years since the 1998 filing of HECO's Final SOP in Docket No. 96-0493, various accounting issues have emerged. These are described in Exhibit C of HECO's SOP in this docket. HECO's position regarding these issues is described on page 25 of Exhibit A:

> "Based on the HECO Companies' already significant commitment to purchased power and the requirement already imposed on the company to rebalance its balance sheet as a result of these obligations, imputed debt and direct debt issues must be addressed in the development of the RFP process and an equity adjustment should be included in the evaluation of bids received, which warrant such treatment, along with the inclusion of transmission-related costs and operations-related costs for each bid."